***Last Updated:*** *May 28, 2015*

**<u>Interim Documentation on the Draft Version of the Public Tool</u>**
**<u>(Proceeding R.14-07-002)</u>**

Energy Division has contracted with Energy and Environmental Economics, Inc. (E3) to develop a 'Public Tool' that will allow parties to test various options for a successor to the existing net energy metering (NEM) tariffs, following Public Utilities Code 2827.1. The draft version of the Public Tool, along with information regarding the development of the draft version of the tool, is available here.

This document is provided as a resource to assist parties in the period between the release of the draft and final versions of the Public Tool. The document is divided into two sections:

- <u>Section One</u> provides a list of questions submitted by parties along with responses from Energy Division/E3 staff.
- <u>Section Two</u> contains a list of calculation, or labeling, errors that have been identified in the draft version of the tool, along with a description of how these errors impact the results.

E3/Energy Division staff will attempt to update this document on a weekly basis. For ease of reference, new comments/questions will be highlighted in yellow in subsequent versions of this document.

**Section One:** This section provides a list of questions submitted by parties along with responses from Energy Division/E3 staff

**1. How are small commercial customers defined?**

Small commercial customers are commercial rate schedules that currently do not have a demand charge.

**2. How does the model treat multi-family dwellings in the ZNE world?**

The public tool uses a small number of Zero Net Energy (ZNE) bins for each utility. None of these bins include multi-family dwellings.

**3. I understand that interconnection costs could not be added in the analysis because there is no "per customer" number that you could use. Is there a way to add interconnection costs on a non-customer-specific basis, at a later point in the calculations?**

Interconnection costs are considered in the model and can be charged either to participating customers or all utility customers in the "Key Driver Inputs" tab of the public tool. The specific values used for interconnection costs can be found on the RR Inputs tab starting at row 404. They are incurred on a "per installation" basis, which is equivalent to a "per customer" or "per account" basis.

**4. Why is the relative difference between without and with DER significantly smaller for PG&E than for the other utilities?**

In the case presented at the workshop, PG&E's average rates are forecast to be lower than those of the other utilities. This drives fewer adoptions and a smaller difference between baseline rates and rates with DER.

**5. Does the definition of "DER" include EE and DR?**

No. Distributed Energy Resource (DER) refers to eligible customer-sited renewable generation modeled in the public tool including: solar PV, solar PV + storage, wind, biomass, biogas, and renewable fuel cells.

**6. Please provide an explanation of how the exports to the grid are dealt with in the 'Share of Cost of Service' (COS) calculations.**

The 'Share of Cost of Service (COS)' is calculated as the net customer payments to the utility divided by the net cost to serve customers considering all usage and all generation that occurs on the customer's premise including exports. Exports are treated as 'negative consumption' for the purposes of the COS calculation. For example, the $/kWh cost of service "credit" for exports will be equal to the export consumption shape times each of the cost components of the cost of service calculation.

To determine revenue allocated to customer segments, calculations are performed at the customer segment level, not at an individual customer level. Exports to the grid reduce customer segment consumption as does DER output that is "consumed" behind the meter. Exports to the grid will therefore reduce customer segment marginal cost responsibility for energy, and potentially for generation, grid transmission, and subtransmission capacity (to the extent that the exports are coincident with the system peak or customer segment diversified peak). Distribution and Primary peak demand are not reduced for DER output, regardless of whether the output is "consumed" behind the meter or exported.

### 7. How were NBCs treated in 'Share of Cost of Service' (COS) calculations?

The draft version of the Public Tool allows non-bypassable charges (NBCs) to be collected in a variety of ways, enabling users to test the impact from participants avoiding or not avoiding NBCs. The impact of the user's selection is included in utility bill. In all cases, the NBCs are included in the cost of service (COS).

### 8. How were interconnection costs treated in 'Share of Cost of Service' (COS) calculations?

The draft version of the Public Tool allows interconnection costs to be paid upfront by participants or included in the revenue requirement and collected from all customers. This selection is made on the "Key Drivers" Tab. The impact of the user's selection affects rates. For example, utility bills are higher if interconnection costs are included in the cost of service and paid by all customers rather than collected from the NEM customer.

### 9. What role do avoided costs play in the 'Share of Cost of Service' (COS) calculations?

Avoided costs that are calculated for the purposes of the Standard Practice Manual (SPM) cost tests are related to, but different, than the scaled marginal costs used in the COS calculations. Some of the underlying marginal avoided costs, such as the marginal avoided cost of energy are the same. Other avoided costs, such as the marginal generation capacity, are calculated differently to allow for the user to select their own resource balance year, for example.

### 10. What role do avoided costs play in the calculations that allocate revenue requirement to customer segments?

The calculations that allocate revenue requirement to customer segments use utility General Rate Case (GRC) settlement marginal costs in all cases except marginal energy costs. Marginal energy costs are the same values used in SPM cost tests and COS calculations and are calculated in the Tool. The allocation calculations use proxies of the peak demand methods used by each utility in their revenue allocation process.

Marginal costs are used to allocate revenues to customer segments following current utility practices. Revenues are allocated in three categories: Generation revenue requirement is allocated based on the sum of generation capacity marginal cost revenue responsibility (MCRR) and energy MCRR. MCRR is the product of unit marginal costs and marginal cost determinants, such as energy use by time of use (TOU) period or peak capacity. Total subtransmission plus distribution plus customer service revenue requirement is allocated to customer segments based on the sum of the subtransmission MCRR, primary capacity MCRR, distribution capacity MCRR, and customer-related MCRR. Grid or Federal Energy Regulatory Commission (FERC) jurisdiction transmission is allocated directly to customer segment, with no need for the calculation of a grid transmission MCRR.

### 11. If there were more documentation available around the adoption model, including the source or derivation of the payback curve, that also would be extremely helpful.

The webinar we gave on this topic on December 2, 2014 is available here: http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

### 12. How many hours of storage does this model assume for the pricing tab on AF31? Was it four hours?

The assumed storage duration is 3 hours. This number was chosen based on the values in Table B-30 in the DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA report.

### 13. Is there an output tab that displays the average size of the PV and storage systems deployed in a run?

The results tab displays an aggregate "DER Size Breakdown" for the systems that were adopted in a particular run (AE148:AE150). These small, medium, and large size breakdowns are computed relative to a customer's annual load (small is 33% of annual gross usage, medium is 66% of annual gross usage, and large is 100% of annual gross usage). In the adoption outputs tab, there is a detailed list of all systems that were adopted including the size in kW. All storage systems are sized to have a discharge capacity equal to PV nameplate capacity.

### 14. What benefits does the "grid benefits" operation of storage include?

"Grid Benefits" operation includes the following benefits: subtransmission, distribution, energy, generation capacity, losses, RPS energy, and ancillary services.

**15. Is there a way to deploy an excel solver to produce rate designs that keep payback at year 7 or below while maximizing avoided cost benefits?**

No, the iterative nature of the model is not set up to run in this way.

**16. We ran a case retaining the ITC at 30% and saw a decline in adoptions in 2017. Why did this occur?**

We think this result is due to the data that we used to seed the model with pre-2017 adoptions. We are looking into this result and will let parties know if a change should be made in the 2015-2016 seeding data. We think that the 2017 result is correct.

**17. The adoption rate from 2019 for PG&E appears flat. Intuitively, since solar prices continue to decline and rates continue to rise in the model after 2017, would we expect that the economic proposition driving customer adoption would result in continued growth in adoption rates?**

This result is a function of the S-curve methodology the model uses to forecast how fast market adoptions approach the expected ultimate saturation penetration. With this approach, an unsaturated market will see rising incremental adoptions, one that is approaching saturation has declining annual incremental adoptions, and a fully saturated market would have no incremental adoptions. Similar year on year adoptions can occur even as rates increase and costs decrease past the mid-point in the S curve as the market approaches saturation. In this case, the improved payback 'makes up' for the natural slowdown as saturation increases.

**18. Should cell I551 (and j552, k553, … AV591) be equal to zero?**

No. Depreciation begins when property is placed in service.

**19. Should cells J877 and K877 contain values?**

No. SDG&E's generation net plant figure is at year-end 2013. If these cells were non-zero the accumulated depreciation for years 2012 and 2013 would be double counted.

**20. Are all the grid charges for the DER Options ($ / kwh exported, $ / nameplate, etc.) scale with the default rates?**

Yes.

**21. Is the $ / Nameplate kW Grid Charge for DER a $ / kW / Month, or $ / kW / Year input?**

$/kW-yr. We will fix the labeling in the final version of the Public Tool to make this clearer.

**22. I set up a case with all behind the meter consumption at retail rate, while all exported kWh are given a fixed FiT rate of $0.87 / kWh. This was accomplished by (a) set**

**"Compensation Structure" to "Retail Rate Credit + Value Based Export Compensation" (b) set ALL fields for "Value-based Compensation" to "No", and kept the societal adders empty (c) set "Grid Charge (exported DER generation)" to -0.87. Is that the right way to make the model calculate results with a user-defined FiT rate instead of a model calculated value based FiT rate?**

We recommend modeling a flat feed-in tariff (FiT) by setting all fields for 'Value-based Compensation" to "No" and putting the $0.87/kWh value in the Societal Value Adder. You can allow this value to increase, decrease, or remain flat over time by entering various nominal escalation rates. Entering a negative grid charge will not achieve the same result. If you select value-based compensation, the model will not calculate compensation due to grid charges or any other bill savings. The same effect holds for exports under an asymmetrical rate. If you select "Full Retail Rate Credit" for compensation structure and add a negative grid charge, the payment will be incremental to reductions in the variable portion of bills. Moreover, a negative grid charge will not hold at all if it causes a customer's annual bill to become negative. Any negative grid charge benefits beyond a $0/yr total bill will be ignored.

**23. Why are forecasted annual incremental kW adoption falling off sharply on all results post 2020 / 2022? I checked all the results after model run, and I see that the market was nowhere near saturation at 2025.**

Many of the most lucrative bins are approaching saturation penetration by 2020/2022. The penetration by bin can be found in column H of the Adoption Outputs tab. Keep in mind that full penetration is not 100% but rather the technical potential %'s found in the Advanced DER Inputs tab. Also, the S-curve methodology used in the model adoption logic predicts the highest annual installation years will occur when a market or bin is 50% saturated. Once a market or bin surpasses this penetration levels, adoptions will continue to increase, but at a slower pace as it approaches full saturation. For more information on the adoption and S-curve logic, please see the December webinar that focused on this part of the model (link can be found at http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm).

**24. I see that if we change RPS levels (33% to 40% to 50%), the amount of kWh discharged from battery storage also increases. Why is this?**

The annual kWh discharge for storage dispatched for grid benefits is higher at higher Renewable Portfolio Standard (RPS) levels because there is more opportunity and value for performing energy arbitrage. There are more hours with overgeneration and curtailment in the higher RPS levels, while the peak daily usage net of non-dispatchable generation is not substantially reduced (i.e., the "duck curve"). RPS level does not affect dispatch of any individual storage system dispatched for TOU arbitrage or demand charge minimization, although it may affect aggregate storage adoption through rate level impacts.

**25. The forecasted incremental adoption kW for 2015 and 2016 seems to be fixed. By changing ITC levels for 2017 and forward, it does not have any impact on adoption kW**

**for 2015 and 2016. But I would think the forecasts for 2016 would have a portion of "gold rush" last minute adoptions build in to take advantage of the ITC before it decreases, and that "gold rush" should have shifted to 2017 and further if I changed ITC so it does not decrease in 2017. Is E3 assuming there is no "gold rush" in 2016?**

Correct, there is no "gold rush" logic in the model. We fix 2015 and 2016 kW adoption to be based on the existing rate structures. We believe that this is appropriate because, in order to simplify the model, we assume that the new residential rates and the successor tariff(s) to NEM do not go into effect before 2017. 2015 and 2016 adoptions do incorporate the full benefit of the Federal investment tax credit (ITC).

**26. In the model, how exactly would forecasted DER installation from a previous year affect RR for the current year, and forecasted kWh sales for the current year? For example, does 2018's RR take into account under-collection / cost shift from the DER installed in 2017 and before, and add that under-collection to a base 2018 RR? Does the kWh generated from 2017 DER adoptions change forecasted kWh for 2018, and thereby impact rate design for 2018?**

Yes, incorporating the cost impacts of DER and any associated cost-shift is a key function of the model. For example, in 2020 the revenue requirement incorporates all avoided costs of DER on the system through 2019, although it does not include a forecast of 2020 DER adoption. Also, 2020 billing determinants incorporate all DER on the system through 2019. Using the total revenue requirement and total billing determinants, the model calculates rates that fully recover the revenue requirement and necessarily incorporate any cost-shift due to DER.

**27. Please look at Slide 52 from the Workshop slides. The Without DER CoS % for PGE and SDGE are pretty fairly even across different classes, while SCE's without DER CoS jumps all over the place from 120% at Res, to 90% at Small Commercial, back to 120 in Large Commercial, dropping all the way to 59% for Industrial. Why is this?**

In reviewing the results shown on Slide 52, we recommend that Parties focus on the changes in CoS between the "without DER" and "with DER" cases. For that comparison, the single driver of change is the introduction of DER. Trying to interpret the differences in "without DER" across classes and utilities is more challenging. There are multiple changing drivers of these differences, including:

1. Differences in utility marginal costs
2. Differences in utility revenue requirements by functional component that change the relative weight of marginal costs in the full cost of service (different EPMC factors by function)
3. Differences in the stylized customer-segment rates (which are aggregations of multiple rate schedules)

4. Differences in characteristics of DER participants within the customer segment and non-participants within the segment, which is partially a function of the customer-segment stylized rates

Because of the many factors that contribute to differences in "without DER" CoS recovery between classes and utilities, it is not practical to provide a simple description of the exact drivers of the differences. Moreover, the dynamic updating of the model marginal costs, revenue requirements, and rates for adoptions within each utility and across all utilities makes it difficult to isolate any particular driver (other than the with and without DER effect for each customer segment).

That said, we provide two examples that identify the main drivers of why the "without DER" CoS recovery is lower for SCE's small commercial and industrial classes than those of PG&E and SDG&E.

In 2020, small commercial customer-related costs are about $3.41 per day for PG&E and $1.19 per day for SCE. Turning to the current retail rates, we see customer charges for small commercial of 37 cents per day for PG&E and 96 cents per day for SCE. This indicates that PG&E is collecting a far smaller share of its customer costs through the customer charge than SCE. Therefore, similar to the residential class, the larger PG&E customers would be paying more than their cost of service. Since PG&E participants are far larger than the customer segment average, a CoS% far above 100% is to be expected. SCE, on the other hand, has a customer charge that is close to its cost of service. Moreover, while the SCE participants are larger than the segment average, they are only about 2.5 times the average, while PG&E's are about 7 times the average. Given the small difference between customer cost of service and rates, and the smaller difference in size, the customer size impact will be minimal and the CoS% ratio is driven by other factors such as the differentials between the summer and winter energy rates and the marginal energy costs. SDG&E's small commercial fixed cost collection falls between those of SCE and PG&E. SDG&E's small commercial energy charges are also not time-differentiated, which is contributing to higher SDG&E participant CoS.

The low % COS recovery for SCE industrial participants is driven by participant usage differing substantially from non-participant usage. The result is most likely due to insufficient data and small sample bias. There were very few industrial customers in SCE that adopted NEM through 2012, and the few that did had very low usage relative to the class average.

While these examples are not comprehensive in explaining each number on the table, they do illustrate the impact of some of the numerous factors that can drive the CoS % recovery results (mainly marginal costs, EPMC factors, participant characteristics, tariff design).

**28. One surprising result from the draft Public Tool is that the future escalation in SCE's and SDG&E's retail rates is much higher than the growth in PG&E's rates. See Slide 28 from the E3 presentation at the March 30 workshop. SCE and SDG&E average residential rates double by 2035 and even in 2025-2030 are 30% to 50% higher than PG&E's rates. This trend**

**appears to be independent of the amount of DER installed. We have the following questions about elements of the Revenue Requirements model that appear to be driving that result.**

**a. The Public Tool's stated assumption for escalation in Distribution and Generation O&M is with inflation (2%), but the actual annual growth rates for distribution and generation O&M, in the Revenue Requirements model, are 5% to 7% per year for sustained numbers of years. These high and sustained escalation rates can be seen at the following lines of the RR Calculations tab – 147, 418, 534, 705, and 820. What is the basis for this rapid growth in O&M expenses?**

O&M is a function of inflation and plant in service. As an example, if O&M costs for a 1 MW power plant are $40,000 in 2015 then with 2% inflation they are $40,800 in 2016. If a second 1 MW power plant were added, 2016 O&M costs would be $81,600. The $81,600 figure reflects both inflation and changes in plant in service. To smooth the O&M trajectory, we may use net rate base inflation in this calculation in the final version of the Tool.

**b. SCE's distribution capex in Line 363 ($2.1 billion per year) is also much higher than PG&E's distribution capex in Line 91 ($1.4 billion per year), even though the SCE data is for 2011 versus 2013 for PG&E. This appears to result in significant above-inflation growth in SCE's distribution rate base, until past 2030. What are the sources for the distribution and generation capex numbers used in the Public Tool, for all three IOUs?**

For PG&E, E3 used A. 12-11-009, Appendix D, Tables 5A and 5C. We are updating SCE's figures with 2012-2014 data from SCE's 2015 GRC, SCE-10, Vol. 02, Tables I-1, II-7 and II-8, which will result in starting average annual distribution capex of $1.96 billion per year. For SDG&E, E3 used the 2016 GRC Direct Testimony of Jesse S. Aragon, Table SDGE-JSA-2. The Public Tool includes factors that users may apply to these figures if users wish to adjust capex projections beyond the first GRC period modeled.

**c. What is the sources for the "Capex retired from rate base," for example in Line 476 for SCE? Why does SCE appear to retire $13.1 billion in capex from rate base in 2025 (column W)? Does this impact the revenue requirement?**

Capex retired from rate base reflects capex that has been fully depreciated and has reached the end of its economic life. The $13.1 billion figure is the starting net rate base for SCE. It reduces gross capex by the amount of retired plant. It impacts only O&M cost escalation.

**29. Generally, can we obtain more details on the assumptions and data sources used for the Revenue Requirements model?**

These were provided in the presentation on 16 December 2014. The link to this presentation can be found here:
http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

**30. We have been having difficulty finding the retail rates that the Public Tool has been calculating. For example, the Detailed Rate Outputs section of the Results tab does not seem to work correctly. We input a TOU rate design as the default for residential, but it does not show up in this portion of the Results tab. Or we choose a 2-tier default residential rate, but this section of the Results tab still shows a 3-tier rate. Is there a problem here?**

E3 has not experienced any issues with incorrect rates populating in the detailed rates output section. The model needs to be fully run with the new rate inputs for this output (and all other outputs) to work correctly. All of the detailed rate outputs are stored in the Rate Output Table tab.

**31. What is the methodology and the documentation for the billing determinants data? There is a tremendous number of columns in the Billing Determinants database. How was that data generated?**

Much of this information was provided in the presentation on 16 December 2014. The link to this presentation can be found here:
http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

For each customer bin, DER technology, and DER system size, we used half-hourly generation and load data to calculate all billing determinants that may be required to determine bills in the Tool. Because there are a number of rate designs and compensation mechanisms available in the Tool, the database includes many different energy, capacity, and customer billing determinants that may describe gross usage, all DER generation, exported generation, net usage (measured as gross usage less all generation), or net usage excluding exported generation. All billing determinants are aggregated to an annual level (ex. monthly max demand is the sum of twelve monthly max demands).The Billing Determinants database also includes some general information about the representative customer bins, such as rate territory and customer segment.
Example billing determinants include:

- Energy usage in each TOU period
- DER generation in each TOU period
- Exported energy in each TOU period (based on half-hourly netting)
- Energy usage in each tier
- Maximum monthly demand (12NCP)
- Maximum demand in each TOU period
- Ratchet demand by season
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The following table summarizes the dimensions of the billing determinants that can be found in the file: